ENHANCED OIL RECOVERY

by

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INTRODUCTION

When an oil well is drilled, the natural expulsive forces of the reservoir drive the oil to the producing well. As these natural forces are gradually diminished, production begins to decline until, finally, oil no longer flows to the well. This primary production, as it is called, usually only results in recovery rates of 20-30% of the original oil-in-place (OOIP). The National Petroleum Council estimates that by the year 2000 less than 10% of U.S. production will be from primary production from known fields.

The huge quantity of oil left in the ground after primary production is concluded is the target of enhanced oil recovery techniques. The overall term "enhanced oil recovery" (EOR) encompasses the variety of techniques and methods which increase the recovery of oil above that which can be recovered through primary production. Before the adoption of the term "EOR", oil production was classified as either "primary", "secondary", or "tertiary". When the technologic differences between "secondary" and "tertiary" became less well defined, and since both terms have been confused with geologic terminology, "secondary" and "tertiary" are now being discarded in favor of the all inclusive term "enhanced oil recovery". The U.S. has approximately 30 billion barrels of proved reserves. Estimates as to how much EOR can add to reserves vary from 15 billion barrels to 110 billion barrels. Regardless of which estimate proves correct, enhanced recovery promises to add substantial amounts of production in the years to come.

The 1986 biennial survey of EOR projects by The Oil and Gas Journal reported that there are 512 reported U.S. projects at this time (1). 108

additional projects are targeted to commence over the next two years. Current EOR projects contribute almost 605,000 barrels of oil per day, representing 6.7% of total domestic crude production. Tables 1 and 2 list U.S. EOR projects and their daily production.

In this paper, current EOR techniques will be discussed. Secondary recovery will cover immiscible gas injection and waterflood. The major tertiary methods will include thermal, miscible gas displacement and chemical processes. A section will also be devoted to a discussion of EOR in Ohio. For the Ohio EOR material, several consulting geologists and operators were interviewed in order to get current information and opinions.

SECONDARY RECOVERY

When first brought into production, most oil fields have sufficient natural forces to push their oil out of the reservoir to the production wells. The hydrostatic pressure of the reservoir fluids or the pressure of expanding solution gas provides this natural expulsive force. As these forces are depleted, the primary production rate declines sharply if enhanced oil recovery techniques are not employed.

Historically, the main enhanced recovery technique used by operators has been injection of a fluid to aid the natural pressure forces. These so-called secondary recovery methods involve the injection of gas or water into the reservoir. Immiscible gas injection and waterflooding have proven to be effective in oil recovery but usually do not recover more than 20% additional oil even under optimal conditions.

Waterflooding

Following reservoir pressure declines, oil production can be increased by injection of water to push crude oil toward producing wells. Waterflooding was discovered in the 1870's in the Pithole City area of western Pennsylvania. A leak from an adjacent water-bearing geologic structure ruined production in the affected well but increased production in adjacent wells. By the early 1900's, circle pattern waterflooding was in rather extensive use in the Bradford area of Pennsylvania. By 1973, waterflooding was contributing close to one-half of total U.S. production (2).

Waterflooding involves injection of water, either fresh or connate, into the production zone through pressure boreholes in a volume equal to or greater than the amount of fluid produced. This results in the formation being kept closer to optimum pressure, prolonging the life of the field. Water can raise the reservoir pressure quickly because of its high density, efficient displacement characteristics, and relatively incompressible nature. Most waterfloods increase production within six months to a year. A quick response is dependent on efficient operating policies. These consist of: (1) Shutting in wells that produce excessive free gas; (2) Increasing lift capacity from wells that produce only solution gas; and (3) Accelerating waterflood development drilling (3).

Economically, waterflooding is quite feasible at very low crude oil prices. The process was in heavy use before the price jumps of the 70's, that is, at $3.00/Bbl. or less. Even in high transport-cost-to-market areas, such as Alaska, considerable water injection has been used.

The two major problems associated with waterflooding are imperfect sweep pattern efficiencies and the resistance of water to mix with oil, resulting in large quantities of unrecovered oil The advancing waterflood can bypass large portions of the reservoir due to poor well placements or reservoir heterogeneities. In areas not reached because of this imperfect sweep pattern, large amounts of oil are left behind. Because oil and water do not mix, 25-50% of the oil contacted stays as small droplets held within the larger pores of the rock. Chemicals can be added to the water to make it more miscible with oil; this is discussed in the polymer flooding section.

Conclusion

While waterflooding has some problems with mobility and miscibility, it has proved to be an inexpensive way to prolong the life of an oil field. Generally, a waterflood will add a significant amount of production though leaving 50-70% of OOIP. The price increases of the 70's caused interest to shift to other EOR methods to recover this residual oil. This made sense since many waterflood were in decline. However, waterflooding is not dead as a recovery method by any means. For example, 25% of Shell's oil production in Michigan results from waterfloods started between 1978 and 1981 (3).

Immiscible Gas Injection

Secondary recovery via natural gas injection has been used in this country since the turn of the century. It was originally utilized mainly for pressure maintenance but later came to be seen as a method of increasing oil recovery. Low pressure gas injection is intended to repressure the reservoir and drive oil out of the production zone.

The procedure has a very low efficiency, usually adding only about 5% to recovery from a field. The unfavorable mobility ratio of the process is largely to blame. Since the gas is immiscible with oil and of lower viscosity, it bypasses the bulk of the reservoir oil (2).

Conclusions

For many years, immiscible gas injection methods were widely used, regardless of the poor efficiencies. This was due to price controls that kept the price of natural gas at an artificially low level. Many operators felt the gas was worth more for reinjection than its low market price. Since this situation has now turned around, it is unlikely that gas injection will be used to any extent in further recovery projects.

THERMAL PROCESSES

It has long been recognized that heat improves the productivity of wells producing low API gravity oils, but full scale commercial use of this knowledge did not start until the 1960's. Thermal processes use heat to lower the viscosity of a heavy oil, enhancing its ability to flow and allowing it to be driven out of the reservoir. The heat necessary for this viscosity reduction is either surface-generated and injected or is created in the reservoir itself by igniting part of the residual oil. The latter method is called in situ combustion or fireflooding, while the former actually involves two steam related techniques: cyclic steam injection and steam drive or steam flooding.

Thermal enhanced recovery methods are the most established and most productive of the "tertiary" recovery techniques. There are presently at least 201 active U.S. projects producing nearly 480,000 barrels of oil per day (BOPD), or 77.5% of the total EOR production. Its increasing success over the past decade in terms of production and number of projects indicates its status as the most mature EOR technology (1).

In Situ Combustion

In situ combustion, or fireflooding as it is sometimes called, is a process in which part of the reservoir oil is ignited at an air injection well. This creates a combustion zone that moves toward the production wells. The Russians probably did some of the earliest work in this area, igniting an oil sand with glowing charcoal in 1935 (4). The first pilot test in this country was in 1953 and, though it produced only 80 barrels of oil, proved the feasibility of the process. The first commercial application occurred in 1959 (5).

Combustion projects are technologically complex and difficult to predict and control. There are currently 17 active projects in the U.S., producing over 10,000 BOPD. When compared to the 38 projects active in 1971, it becomes obvious that interest has declined in this process. Though originally designed for use on very viscous crudes, the technique is theoretically applicable to a wide range of oils.

The basic process involves injection of hot air, which results in spontaneous ignition of oil within the reservoir. The burning oil front that develops should then proceed slowly through the reservoir. Ahead of the burning front a steam zone develops which mobilizes and displaces the oil in front of it. Fuel for the process is the carbon-rich coke deposited on sand grains when the residual oil in the steam zone is exposed to high temperature thermal cracking. Figures 1 and 2 illustrate this process. Fuel deposition and the related air requirement are the most important factors in combustion projects. If the amount of deposited coke is excessive the progress of the combustion front would be slow and the air requirement would be large. On the other hand, if the oil is parrafin-base and of high API gravity, it could be completely flushed out by the steam front without leaving coke to maintain combustion.

Modifications of the Process

Wet Combustion

Though in situ combustion has a better energy ratio than either cyclic steam combustion or steam drive, the thermal efficiency of the process is still quite low. The problem lies in the low heat carrying capacity of the air that is required to burn the fuel. The air can only carry about 20% of the generated heat ahead of the burning front. Some additional heat is carried into the steam zone by combustion water but 70% of the heat is left behind in the reservoir rock. This residual heat helps recovery somewhat by heating oil above and below the burned zone but is still considered a major inefficiency. For this reason, standard dry combustion techniques have given way to a modified technique called wet combustion, which uses water as a heat transfer agent to scavenge the residual heat. This technique is illustrated in figure 3. Wet combustion can involve either water injected as a slug behind the combustion front or as simultaneous injection of air and water. Wet combustion patterns generally result in lower air requirements and better oil recovery. The first field test of air/water injection was in 1962 in the Loco field of southern Oklahoma. In the process used, called combination thermal drive(CTD), sufficient water for conversion to superheated steam and to saturate the burned zone is injected. One important factor with wet combustion is that volumetric sweep patterns are much higher (5).

Oxygen Enrichment

A relatively new combustion modification that shows great promise is oxygen enrichment. Tests using oxygen enriched air or pure oxygen as the oxidation agent are now in progress. Potential advantages of the technique are high displacement rate, increased cold oil mobility due to CO2 solubility, and higher recovery rates.

Injection of 99.5% pure oxygen should result in the formation of a 93% CO2 combustion gas. Since CO2 is highly soluble in water and oil, this greatly reduces the viscosity of the oil and therefore increases mobility. The carbon dioxide concentrates in front of the steam zone and saturates all the oil it contacts. In addition to viscosity and mobility improvements, the CO2 also causes the oil to swell, resulting in further recovery efficiency due to additional drive. It is worth noting that the produced carbon dioxide can be recovered from the exhaust and used in other EOR projects (5).

Cyclic Steam Injection in Combination with In Situ Combustion

In a very viscous oil reservoir a combustion project can fail because of the high resistance to flow. Downstream of the heat bank an oil bank of cold oil can form that would require a very high pressure gradient to be moved. Cyclic steam injection has been used in conjunction with the combustion in situations like this. Steam is injected periodically at production wells in order to increase the mobility of the cold oil bank, relieve the pressure gradient, and allow combustion to continue.

Conclusions

In situ combustion has proven successful for both heavy and light oils but is generally favored for viscous, low gravity crudes, since they assure the coke necessary for the combustion process. Combustion techniques give fairly high recovery rates, averaging 50%. The acceptance of the process has been slow, actually declining in use during the 70's before stagnating at its present levels. Both economic and operational problems have contributed to this lack of interest. The process requires sufficient manpower to engineer and operate a combustion project and the return on investment is slow in coming. Cyclical steam, on the other hand, requires a comparatively low initial investment and gives a more immediate response. Severe operational problems have been reported on field projects. The process has a tendency to sweep only the upper part of the oil zone, so sweep efficiencies are poor in a very thick formation. This inefficiency is caused when water condensed from the steam front settles below the steam front and combustion gases, causing the gases to be concentrated in the upper part of the oil zone. Other problems include formation of oil-water emulsions with the consistency of whipped cream, corrosive waters, and toxic gases. These problems all cause additional production expenses which tax the economics of the process.

<u>Cyclic Steam Injection</u>

Cyclic steam injection, also known as steam stimulation or "huff and puff", is a relatively simple method using injected steam to increase recovery from a production well. The method was accidentally discovered in 1959 when steam broke through the surface during a steam injection trial in Venezuela. It was decided to relieve the pressure by backflowing the steam injection well, resulting in impressively high oil production rates. Steam stimulation has since become an established EOR technique. California, with its large reserves of heavy oil, has benefited the most from steam stimulation, as well as the other thermal processes.

The cyclic steam process involves the injection of high quality steam into a producing well. The well then may or may not be allowed to soak for a period of time. There is a difference of opinion regarding the length of time the soak should take. If the well is produced immediately, a large amount of heat is lost with the produced steam. On the other hand, heat lost to base and cap rock is a function of time so large amounts of heat can be lost in that way. Generally, a soak of one to five days is the accepted practice. The well is then put into production for a period of weeks or months. When production has declined appreciably the process is repeated. The process is illustrated in figure 4.

The average increase in oil production rate with cyclic steam injection is ten to thirty times, though increases of up to one hundred times the pretreatment rate have been reported. The reservoirs are usually rather shallow and wells are drilled close together since the heat does not penetrate far from the wells. The number of cycles is limited since the area near the well gets flushed out. In California reservoirs, which are generally steeply dipping structures, many cycles are often possible due to gravity drainage. In flat reservoirs, where gravity does not aid flow, the number of cycles is much more limited (2). Steam stimulation is, in general, less expensive than steam drive. However, steam drive is capable of higher recovery. The common practice is to use cyclic steam injection first, implementing a steam flood after production has declined appreciably.

<u>Steam Drive</u>

Steam EOR processes in 1986 are making over 468,000 BOPD with steam drive giving the bulk of that production (1). Steam drive is currently the leading EOR technique and some experts see it as the most universally applicable one.

The steam drive, or steam flood, process is similar to waterflooding. A suitable well pattern is chosen, steam is injected into some wells, and oil is produced from other wells. Ideally, a series of zones are formed as the steam flood progresses. A steam saturated zone forms around the injection well; the temperature here is nearly the same as the injected steam. As the steam moves away from the well, its temperature drops as it expands in response to the pressure drop. At some distance from the injection well, steam condenses and forms a hot water bank. In the steam zone, steam distillation and gas (steam) drive act to displace the oil. The hot water zone should cause physical changes in the oil and in the reservoir rock to enhance oil recovery. These changes include thermal expansion of the oil, reduction of viscosity and residual oil saturation, and changes in relative permeability (6). The basic steam drive process is shown in figure 5.

The actual performance of a steam drive is quite different from the ideal model. Injected steam usually fingers its way through the easiest conduit and quickly reaches the producing well. Over time the steam finger, being less dense, migrates upward in the reservoir while hot water and condensate heat the lower part. This gravity override results in uneven vertical sweep efficiencies that are not considered ideal for maximum recovery. One way to reduce the sweep inefficiency is to inject steam at the bottom of the reservoir. This reduces the severity of the gravity override if the reservoir is homogeneous and there is no bottom water (easy steam path). Chemicals and high-temperature gels have been developed to plug thief zones in heterogeneous reservoirs (7).

Steam drives can be applied to a wide variety of reservoirs. The main limiting factors for a reservoir are depth (less than 5000 ft.) and reservoir thickness (greater than 10 ft.). The depth limitation is due to the critical pressure of steam, the thickness by the rate of heat loss to cap and base rock. Other beneficial reservoir parameters include: (1) oil gravity above 12°API; (2) oil viscosity 100-10,000 cp at reservoir temperature; (3) permeability above 50 md; and (4) porosity above 25% (7).

Conclusions

Steam drive oil recovery is the most widely accepted and proven EOR technique, but is economically feasible only as long as the net value of the oil produced exceeds the cost of production. In addition to the fuel costs, most other aspects of production are costly, including well completions, capital and operating costs for steam generation and produced fluid demulsification and dehydration. In addition, steam processes are energy intensive, therefore they are not helped by crude oil price increases as much as other EOR methods. The large quantities of fresh water required puts an additional constraint on the potential of this process. The many advantages of this process should allow continued development of this method, at least in the near future. Recovery rates of 45-50% of OOIP for this process mean that it can be expected to recover at least several billion barrels of additional oil in the years to come.

MISCIBLE DISPLACEMENT PROCESSES

One of the key problems in oil recovery is overcoming the surface tension forces which bind the oil to the rock. If the interfacial tension between the invading fluid and the oil can be reduced, then the surface tensions are also reduced. This is the object of miscible flooding. Miscible fluids are completely soluble in one another; their interfacial tension is zero, resulting in no distinct fluid-fluid interface. There are only a few fluids which are miscible with oil and water and economically feasible for enhanced recovery. The three miscible displacement processes which have received the most attention use liquid hydrocarbons, CO_2, or inert gases.

<u>Miscible Hydrocarbon Displacement</u>

Liquid hydrocarbons such as naphtha, kerosene, gasoline, alcohol, and liquified petroleum gas (LPG) products such as ethane, butane and propane are miscible with reservoir oil immediately on contact. Miscible hydrocarbon processes are meant to recover oil by forming a miscible zone that pushes an oil bank toward the producing well. There are three main processes that achieve this effect. The first, known as the miscible slug process, involves injection of a slug of liquid hydrocarbon, followed by natural gas, or gas and water, to drive the slug through the reservoir. In the second, the high pressure gas process, lean gas is injected at high pressure in order to cause retrograde evaporation of the crude oil and formation of a miscible phase. Finally, the enriched gas process entails injection of a slug of natural gas, enriched with ethane through hexane, followed by lean gas or lean gas and water. The three processes are illustrated in figures 6, 7, and 8. It is important to inject water alternately with gas for mobility control since the injected slug is more mobile than the oil. The high mobility of the slug combines with the high mobility of the displacing gas to give low sweep and displacement efficiencies. If the slug injection is followed by gas and water the mobility is reduced and sweep efficiency is improved (6).

The range of reservoirs suitable for these techniques is fairly limited. Due to the pressures involved, fairly deep (5000 ft.) fields are required both to avoid the cost of repressuring and the threat of blowing through the overburden. Generally, the processes work best on very light oil in a homogeneous, low permeability reservoir (6).

Though there have been technical successes with hydrocarbon displacement techniques, the future for them is poor. The main problems have to do with mobility control and economics. The very poor mobility characteristics often cause channeling and bypassing of oil even in homogeneous sands. In addition, the increased value of hydrocarbon gases has discouraged use of this energy intensive method.

CO_2 Miscible Flooding

Carbon dioxide flooding involves the injection of CO_2 into a reservoir where it dissolves in the crude oil, reduces its viscosity, swells it, and vaporizes it into the CO_2 phase. This results in high displacement efficiency of contacted oil. CO_2 injection appears to be the most promising of the techniques aimed at miscibility. Carbon dioxide injection has been field tested on a small scale for many years. Interest in the process picked up when oil prices began rising and as many waterflooded fields approached the end of their productive lives.

Only in the last few years have large-scale CO_2 field projects begun to prove economically feasible. In 1986 there are 38 reported U.S. projects, producing over 28,000 BOPD (1). The production figure is small mainly because many of the projects are new and there is a time lag before increased recovery occurs. Operators in the Permian Basin of western Texas and southeastern New Mexico are confident enough in the process to have invested two billion dollars in various field projects. The Permian Basin could yield an additional five billion barrels of oil, requiring 30 trillion cubic feet of CO_2 and extending the life of the affected reservoirs by 30-40 years (8).

Though CO_2 is not completely miscible with most crude oils, it can displace nearly all the oil it contacts. This is achieved by injecting the CO2 under pressure (1800-2500 psi) in order to make it nearly as dense as the oil. After mixing with the oil, the interfacial tension is eliminated and the viscosity of the oil is reduced. The CO2 increases the bulk and relative permeability of the oil, causing it to swell so that reservoir pressure increases and the oil flows more readily (2). After a CO2 flood has been completed, part of the gas comes out of solution due to pressure reduction, causing a further gas drive within the reservoir.

There are three variations of CO2 flooding: (1) Injection of CO2 in a slug, followed by water or carbonated water; (2) Injection of carbonated water directly; and (3) Continuous CO2 injection. The most popular method has been the use of a liquified gas slug followed by water. Figure 9 illustrates this method. The desired effect is for the CO2 to mix with the crude and form a single-phase liquid which is much lighter than the original oil. This miscible oil bank can then be pushed through the reservoir by the following water drive (6).

CO2 flooding is known to work under a wide range of conditions. Generally the projects have involved API gravities from 32° to 42° with low viscosities at high depths (4300-9000 ft.) and low permeabilities. The high pressures used in the process preclude its use in shallow reservoirs. The residual oil saturation of a reservoir is an important factor; a saturation of 25-30% is considered the minimum.

The mobility of CO2 has proved to be the biggest problem of the process. Carbon dioxide shows a tendency to finger through the reservoir, sharply reducing the sweep efficiency, if the reservoir is heterogeneous. Foams and gels have been developed that are successful in mobility control. The need for a detailed description of reservoir heterogeneities has also become apparent. A highly fractured reservoir is generally considered unfavorable because of the mobility control problems.

Another basic problem is availability of large amounts of cheap carbon dioxide. Most projects presently use natural sources of CO2 that have been discovered during oil exploration. The largest known reserves of natural CO2 are in the oil-producing basins of Wyoming, Utah, Colorado, and New Mexico. The big projects in the Permian Basin use CO2 that is transported by pipeline from sources in Colorado and New Mexico, as well as CO2 from natural gas processing plants.

Sources other than natural deposits that have been considered are stack gas from coal-fired power plants and as a by-product of many chemical and refinery processes. In the past these resources were considered uneconomical but the improved value of CO2 for oil recovery has prompted renewed interest in exploiting any source of the gas.

Conclusions

Carbon dioxide injection appears to be the most promising of the miscible EOR processes, though in the immediate future it will probably be confined to low gravity oil fields in relatively close proximity to natural CO2 sources. Operators generally hope for 10-15% recovery of the oil remaining after waterflood. Mobility and sweep efficiency problems usually keep the process from recovering a higher percentage of the oil-in-place.

Estimates vary as to how much additional oil CO2 floods can add to recoverable resources. Projections call for anywhere from 3-12 billion additional barrels. One study said that CO2 floods in Texas, California, and Louisiana could add 11.7 billion barrels to our reserves by the year

2000 (2).

The supply source of CO_2 is a major factor inhibiting more widespread use of the process. At present, the high cost of CO_2 kills the prospect of CO_2 floods in areas out of the economic pipeline range of natural CO_2 sources. Major improvements in transportation and recycling of CO_2 need to be made to fully realize the potential of this recovery technique.

Inert Gas Injection

Inert gas oil recovery projects date from the early part of this century. Generally air or natural gas were the gases used for injection until relatively recently. The oxygen in air causes severe operational problems such as spontaneous ignition and corrosion. The ever rising cost and limited supply of natural gas has made it necessary to search for substitutes in gas injection. "Inert gas" (either pure N_2 or a mixture that is predominantly N_2) is the substitute receiving the most attention (6).

The goal of inert gas injection is to achieve miscibility between the injected gas and the reservoir oil. Once miscibility is achieved, capillary effects disappear and the displacement efficiency approaches 100% in the swept zone. Inert gas injection will give higher recoveries in comparison to water drive in many reservoirs with very low permeabilities. The two main sources utilized for inert gas are boiler flue gas and gas engine exhaust.

The biggest problem of using flue gas or engine exhaust is corrosion, which caused most early projects to fail. Water vapor, CO_2 and nitrous oxides are all present in the gas and can form corrosive acids if not treated. Most projects use scrubbers and catalysts to remove these impurities before injection. An additional factor is that natural gas in the reservoir is contaminated and produced gas will contain increasing amounts of the injected gas. This necessitates blending of the gas with natural gas streams to make it marketable (4,9).

Conclusions

Inert gas injection is a good recovery technique that can be used to advantage in certain reservoirs, especially ones with very low permeabilities. There are few problems associated with the process that cannot be solved by proper operation. The only major disadvantage is the economic burden caused by contamination of produced natural gas. The use of this process should continue to climb somewhat in the future as reservoirs are determined to be favorable for it.

CHEMICAL PROCESSES

Introduction

Chemical EOR processes have been researched and tested for a number of years. Many techniques are successful or show promise while others have yet to prove economic. Most chemical oil recovery processes are very complex and their effects are not completely understood. For the most part, these processes are only applicable in a limited range of reservoir conditions. The three important chemical processes are surfactant/polymer injection, polymer flooding, and caustic flooding.

Surfactant/polymer injection is designed to lower interfacial tension of reservoir oil against the injected fluid and to displace oil that cannot be displaced by water alone. In polymer flooding, the viscosity of injected water is increased by the addition of a thickening agent (polymer). This is meant to increase the effect of water in oil displacement and sweep efficiency. The third chemical process, caustic flooding, uses chemical additives to reduce the interfacial tension. The additives react in the reservoir to form surfactants, detergent-like substances which lower the interfacial tension.

In general, chemical processes have shown a steady increase in use during recent years. Polymer flooding is clearly the leader, with production in 1986 of 15,313 out of 16,901 BOPD total production for all chemical processes in the U.S. (1).

Surfactant/Polymer Flooding

Surfactant/polymer injection, also known as microemulsion flooding or micellar flooding, is one of the most complex EOR processes. The surfactant slug is composed of chemicals which act like soap and "wash" the oil out of the reservoir. The polymer is added to water to thicken it and enable it to push the surfactant slug through the formation. Variations of the process have been patented by Marathon, Union and other firms.

In this technique, the surfactant slug (microemulsion) is first injected into the formation. The slug is followed by a mobility buffer solution (polymer) and then the drive water. Figure 10 illustrates this process. Ideally, oil and water are displaced ahead of the surfactant slug and driven toward the producing well. The purpose of the surfactant is to solubilize the oil encountered, reduce the interfacial tension between the oil and water, and push oil out of the reservoir. Mobility control is important for the success of this technique. The mobility buffer prevents rapid deterioration of the slug by the waterflood that follows. A properly designed polymer buffer will move the slug ahead evenly to contact a large portion of the reservoir. Sweep efficiencies of up to 75% have been achieved with this method.

Conclusions

There are many aspects of surfactant/polymer flooding that are not understood, making it very difficult to predict how a project will perform in a specific formation. The process is very expensive and has some operational problems that need to be overcome. The surfactant tends to adsorb to certain minerals and any extraneous reservoir fluid can dilute the slug. Problems such as these are a major cause of slug breakdown.

The difficulty of predicting flood efficiencies hindered more active field work with this process. In addition, the current low price of crude is far below that needed for this method to be economic; some experts say that even $20-25/Bbl. is not high enough to ensure profit with microemulsion flooding (10). A large amount of research needs to be done, but the process should come into more widespread use in the future.

Polymer Flooding

Polymer-augmented waterflooding involves the addition of polymers in a waterflood program to enhance production. The production increase results from beneficial effects by the polymer flood on reservoir heterogeneities and on mobility contrasts between reservoir fluids and drive fluids. The process is quite complicated, but is the most commercially active chemical EOR method at present.

The variability of reservoir permeability is an important factor in oil recovery. Injection fluids generally take the path of least resistance, bypassing less permeable zones and the oil they contain. This effect can be reduced and overall sweep efficiency improved if the mobility of the injection fluid can be made to match the mobility of the reservoir fluids.

While many EOR techniques rely on reducing the viscosity of the oil, polymers do the opposite, increasing the viscosity of the water (11). This reduces the mobility contrast between the drive water and the reservoir oil. When the mobilities are closer together, the water no longer tends to bypass oil in less permeable zones of the reservoir. This results in greater sweep efficiencies and increased recovery of oil from the field.

Conclusions

The effectiveness of polymer flooding is a fairly established concept that has been shown to work both in the lab and in field tests. As is the case with most of the newer EOR techniques, there is room for improvement in the techniques and systems of the process. Though there are some aspects of this method that are not understood and need more research, polymer flooding is the most promising of the chemical EOR processes.

Caustic Flooding

Caustic, or alkaline, flooding uses chemicals such as sodium hydroxide or sodium silicate to reduce the interfacial tension between the injection fluid and the reservoir oil. The earliest recorded field trial in 1925 involved the injection of sodium carbonate in the Bradford field of Pennsylvania; the project was disappointing and not reported in detail (6). The application is relatively simple and inexpensive, but has been plagued with operational problems and unsatisfactory recovery rates.

A reservoir currently under waterflood can be easily converted to a caustic flood by mixing caustic chemicals with the injection water at laboratory-determined concentrations. In the reservoir, these chemicals form surfactants by neutralization of petroleum acids. The surfactants formed at the oil-water interface lower the interfacial tension and form an emulsion of the oil. The simplicity of the process ends with injection and a host of recovery mechanisms are possible in the reservoir. These mechanisms include entrainment, which reduces interfacial tension; entrapment, which improves sweep efficiency; and wettability reversal, which can improve mobility ratios. Each mechanism may or may not be included in a specific reservoir project.

Entrainment occurs by emulsification of the crude oil; oil droplets are suspended in the alkaline drive water and moved toward the producing well. The entrapment mechanism improves the sweep efficiency; as the flood moves through the reservoir, some of the emulsion is trapped in pores and diverts the flow to other flow channels. This reduces water mobility and improves overall sweep patterns. Finally, wettability change can improve oil recovery by reversal of reservoir rock wettability from oil-wet to water-wet (2).

The major disadvantages of the process are loss of caustic to reservoir rock and gypsum plugging. There is a tendency for some reservoir rocks to react with and neutralize the caustic chemicals. Clay components have a particularly rapid and complete reaction with the caustic. Major operational problems have also been reported concerning severe plugging of wells with gypsum. Apparently, gypsum in the reservoir is dissolved by the injected caustic solution and is then deposited at or near the wellbore (1,2).

Conclusions

The caustic flood processes are extremely complex in operation and all the mechanisms involved are not fully understood. Field trials have often proven unsuccessful because of the impact of reservoir characteristics on the process. The poor performance record has resulted in a lack of interest by operators in the techniques. Active projects have been on the decline and presently there are only 8 field projects with production of 185 BOPD (1).

OHIO EOR

Enhanced oil recovery in Ohio has been dominated by gas injection and waterflooding These methods have produced some additional oil, but overall, enhanced recovery has been unsuccessful in the state. The failure of projects has been due mainly to operational and reservoir problems.

The first recorded effort to stimulate oil recovery by gas injection was in 1903 in the Macksburg Pool in Washington County. This test, and another in 1911, was made by I.L. Dunn and two associates, O.C. Dunn and H.E. Smith. These projects, in the vicinity of Marietta, led to the process being called the "Smith-Dunn" or "Marietta" process (12). This marked the beginning of widespread recovery efforts using both natural gas and air injection. Air injection caused some scattered good responses but also brought with it corrosion and maintenance problems. Natural gas reinjection projects came to be a somewhat more successful technique. Waterflooding projects were also initiated in various oil-bearing formations after the process was legalized in the state in 1939. Responses to waterflooding have been disappointing overall.

Gas recycling projects were predominantly used on the "Clinton" Sandstone, as this formation was found to have the best response. Generally, the objective was pressure maintenance to arrest declining production and possibly stimulate recovery. Waterflooding has been moderately successful only in the Berea Sandstone of the Chatham field (13). Both these methods were overall failures due to the same reason: reservoir conditions. The reservoir rocks of the Appalachian Basin have a very low permeability. In addition, they often have a fractured nature which allows rapid transmission of fluids from the injection well to the producing well.

Primary recovery rates from Ohio formations are quite low, usually in the range of 7-8%. Even in cases where secondary recovery has been successful, only about an additional 8% is recovered. This leaves an enormous amount of potential for EOR techniques, but very little has been done in this area. The main reason for this is that small, independent operators are responsible for most of the oil production in Ohio. These operators usually cannot afford expensive, technologically advanced recovery methods, especially since many operations are marginal as it is.

An exception to this general lack of enhanced recovery in the state is an inert gas injection project in Licking County. This project has increased daily production by 500% in Berea wells drilled in 1914. As mentioned earlier in this paper, inert gas injection works well in most formations of low permeability. In this project, natural gas is burned to produce the inert injection gas. A catalytic converter is used to remove the nitrous oxides and the resulting gas is made up of 12% CO and CO_2, and 88% N_2 (14).

Conclusions

Secondary recovery techniques have historically proven to be unsuccessful in Ohio due primarily to reservoir conditions. The inert gas injection project in Licking County shows promise and will undoubtedly be used more extensively. The lack of the presence of major oil companies in Ohio will probably preclude any extensive EOR development for the time being. This may change in the future as Pennsylvania Crude grade oil, which Ohio reservoirs contain, becomes more scarce. This could prompt the companies that refine this type of oil to begin enhanced recovery operations in the state.

The amount of crude petroleum that still remains underground in Ohio has never been determined. While new deposits of modest size are still being discovered, there is considerable oil in so-called "exhausted" fields, whose general location is a matter of record. Since these fields were exploited, in some cases, as much as a century ago, at a time when such concerns as maintenance of reservoir pressure was not even considered, much less understood, when reservoir gas was flared indiscriminately, and when no conservation regulations were in place, production efficiency was at an all-time low. The percentage of unrecovered oil remaining in many American oil fields now abandoned is often 60% of the original reserve. In Ohio, this may be much higher. Therefore, a day will come when EOR technology will be seriously focused on Ohio oil deposits (15).

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Table 1. (1),

Active U.S. EOR projects

	Number of projects 1971	1974	1976	1978	1980	1982	1984	1986	Change from 1984, %
Thermal									
Steam	53	64	85	99	133	118	133	181	+36.1
Combustion in situ	38	19	21	16	17	21	18	17	− 5.6
Hot water	—	—	—	—	—	—	—	3	—
Total thermal	**91**	**83**	**106**	**115**	**150**	**139**	**151**	**201**	**+33.1**
Chemical									
Micellar-polymer	5	7	13	22	14	20	21	20	− 4.8
Polymer	14	9	14	21	22	55	106	178	+67.9
Caustic	—	2	1	3	6	10	11	8	−27.3
Total chemical	**19**	**18**	**28**	**46**	**42**	**85**	**138**	**206**	**+49.3**
Gases									
Hydrocarbon miscible	21	12	15	15	9	12	16	26	+62.5
CO_2 miscible	1	6	9	14	17	28	40	38	− 5.0
CO_2 immiscible	—	—	—	—	—	—	18	28	+55.6
Nitrogen	—	—	—	—	—	—	7	9	+28.6
Flue gas (miscible and immiscible)					8	10	3	3	—
Total gases	—	—	—	—	**34**	**50**	**84**	**104**	**+23.8**
Other									
Carbonated waterflood								1	—
Grand Total					**226**	**274**	**373**	**512**	**+37.3**

Table 2. (1).

U.S. EOR production

	b/d 1980	1982	1984	1986	Change from 1984, %
Thermal					
Steam	243,477	288,396	358,115	468,692	+ 30.9
Combustion in situ	12,133	10,228	6,445	10,272	+ 59.4
Hot water	—	—	—	705	0.0
Total thermal	**255,610**	**298,624**	**364,560**	**479,669**	**+ 31.6**
Chemical					
Micellar-polymer	930	902	2,832	1,403	− 50.5
Polymer	924	2,927	10,232	15,313	+ 49.7
Caustic	550	580	334	185	− 44.6
Total chemical	**2,404**	**4,409**	**13,398**	**16,901**	**+ 26.2**
Gases					
Hydrocarbon miscible	—	—	14,439	33,767	+133.9
CO_2 miscible	21,532	21,953	31,300	28,440	− 9.2
CO_2 immiscible	—	—	702	1,349	+ 92.2
Nitrogen	—	—	7,170	18,510	+158.2
Flue gas (miscible and immiscible)	—	—	29,400	26,150	− 11.1
Total gases	**74,807**	**71,915**	**83,011**	**108,216**	**+ 30.4**
Other					
Carbonated waterflood	—	—	—	—	
Grand total	**332,821**	**374,948**	**460,969**	**604,786**	**+ 31.2**

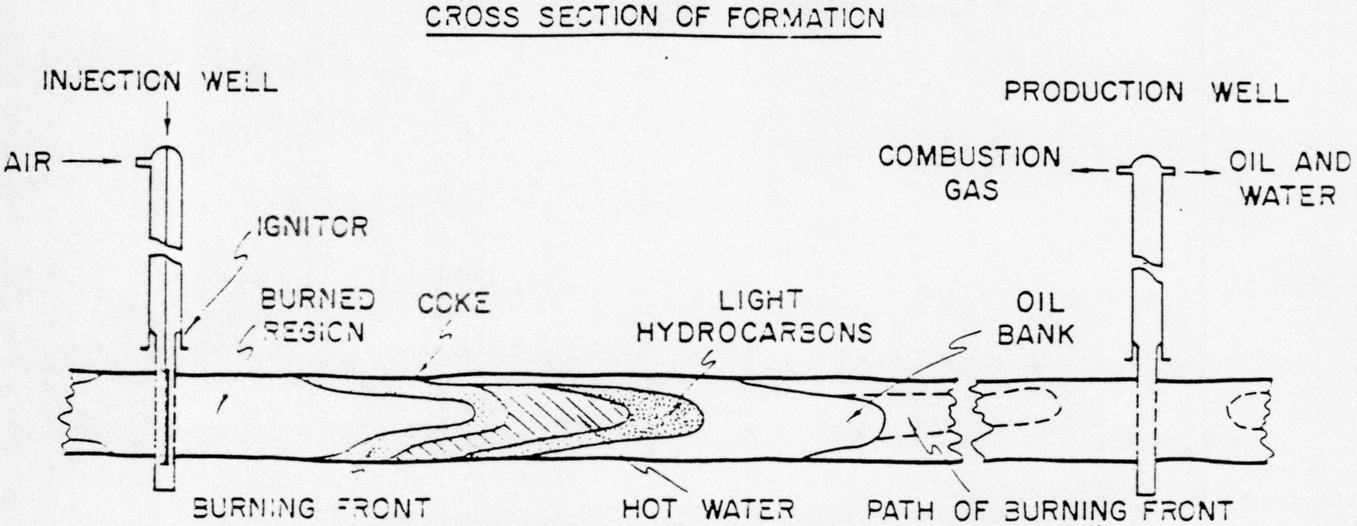


Figure 1. Diagram of in situ combustion process (6).

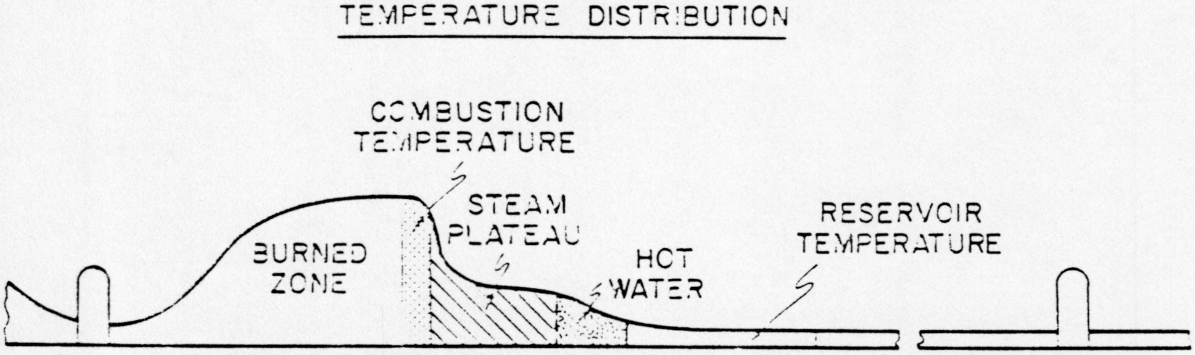


Figure 2. Temperature distribution - in situ combustion (6).

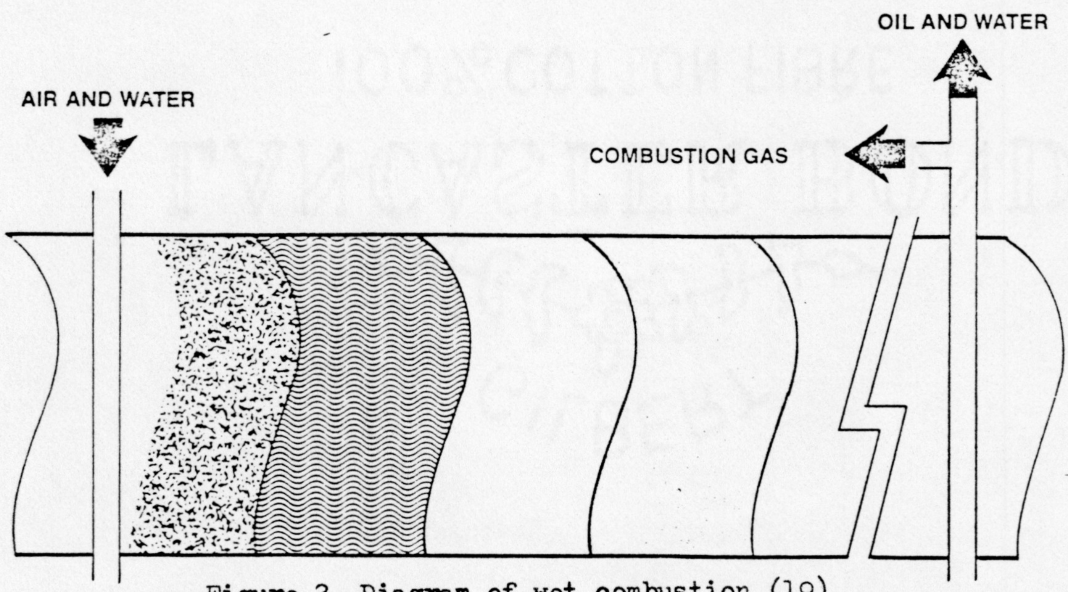


Figure 3. Diagram of wet combustion (19).

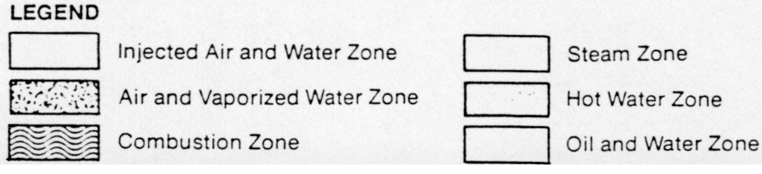


Figure 4. Diagram of cyclic steam injection process (19).

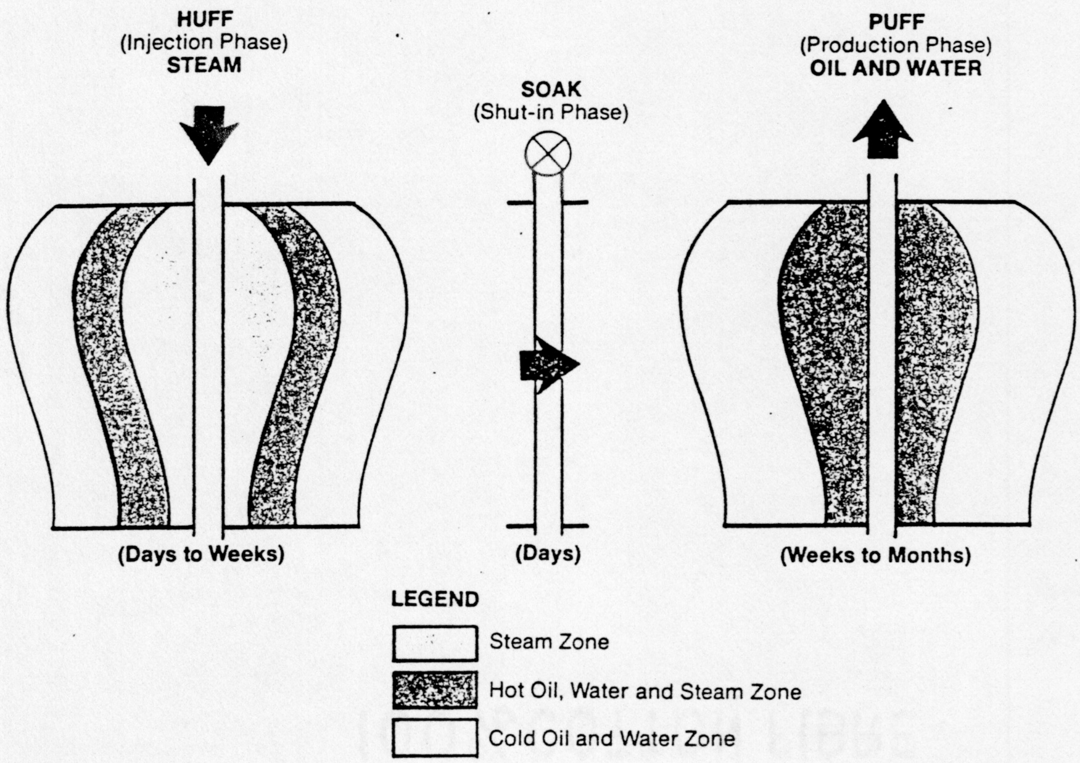
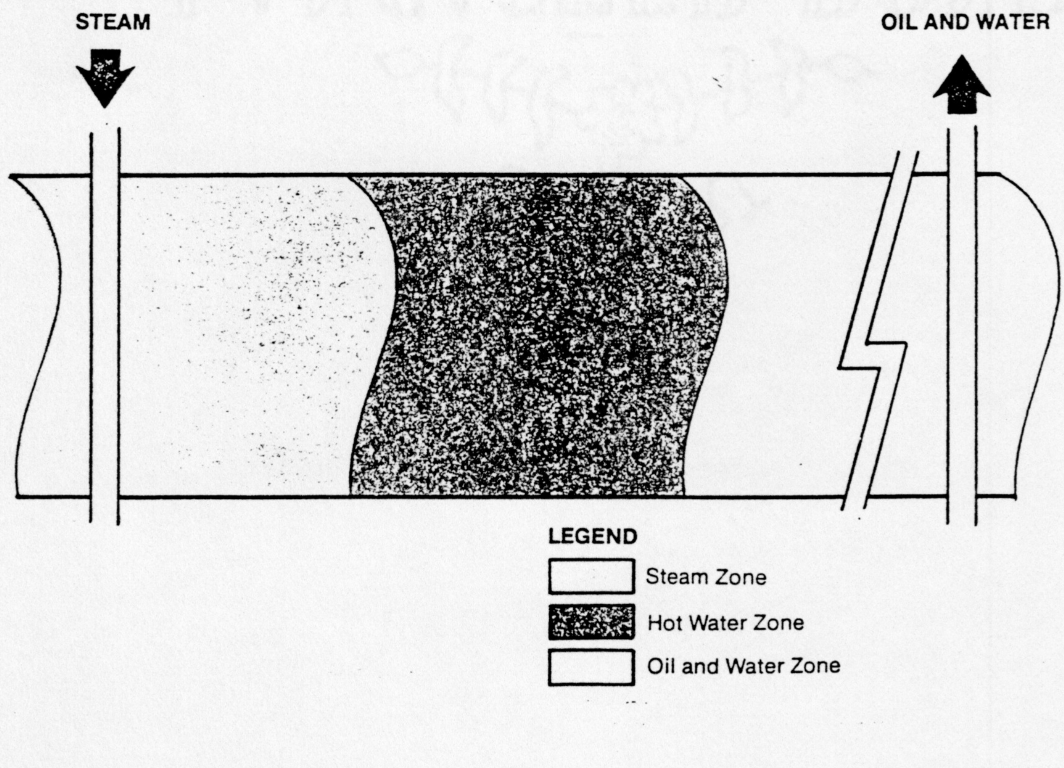


Figure 5. Diagram of steam drive process (19).



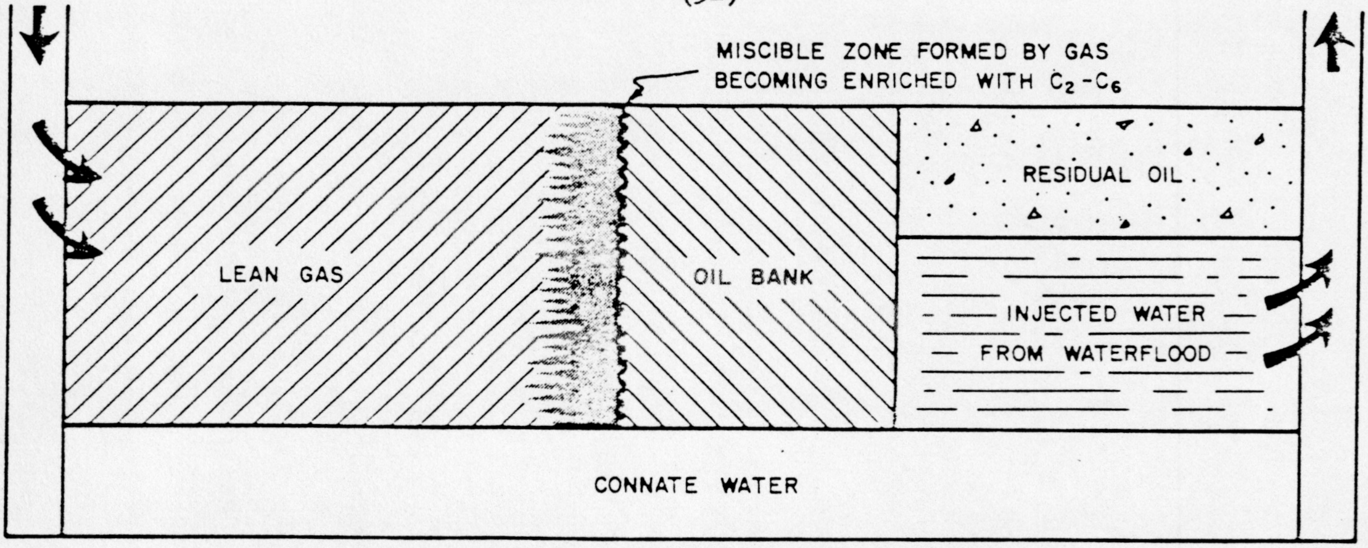


Figure 6. Diagram of lean gas process (6).

Figure 7. Diagram of miscible slug process (6).

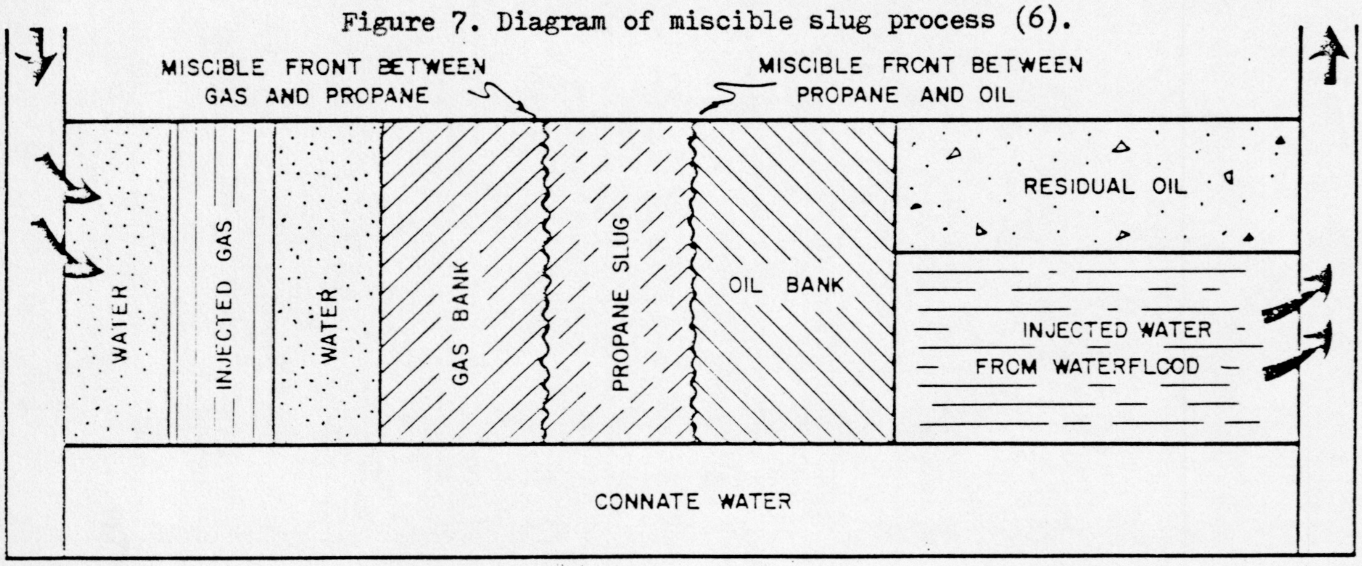


Figure 8. Diagram of enriched gas process (6).

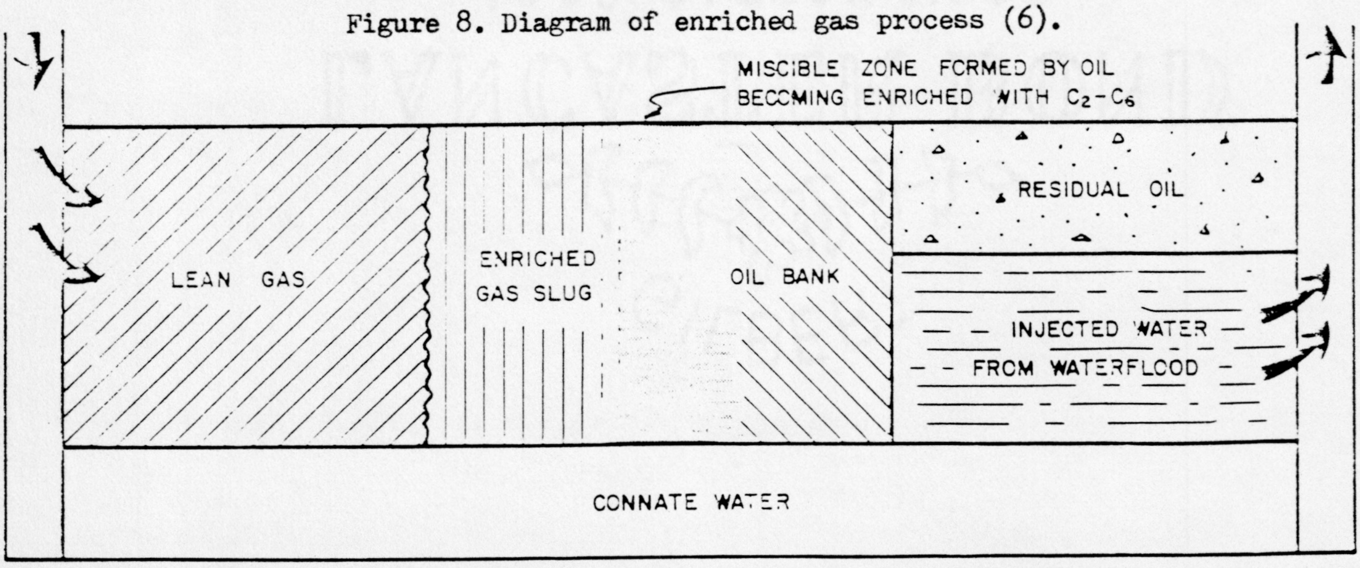


Figure 9. Diagram of CO2 miscible slug process (19).

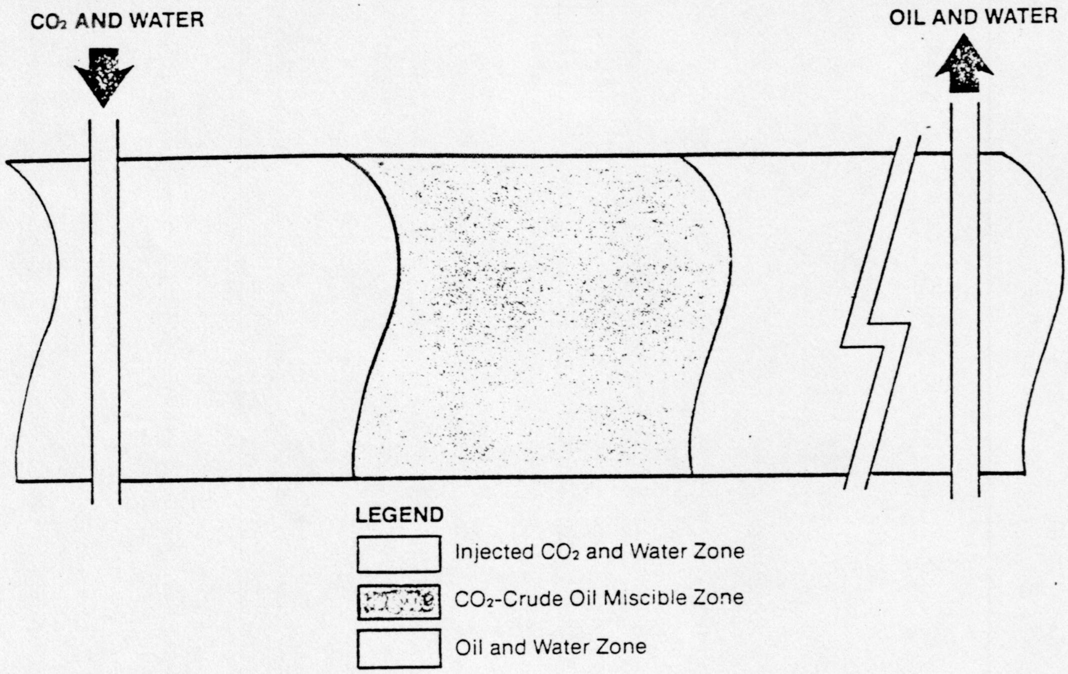


Figure 10. Diagram of surfactant/polymer flooding (19).